UNITED STA.ES ENVIRONMENTAL PROTECTI.N AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

0,300c

UNDERGROUND INJECTION CONTROL PROGRAM

Final Permit

Class II Enhanced Recovery Well

Permit No. WY2819-04366

Well Name: Shoshone 66 No. 66

Field Name: Circle Ridge

Wind River Indian Reservation

County & State: Fremont County, Wyoming

issued to:

Marathon Oil Company
1501 Stampede Avenue
Cody, WY 82414-4271

October 1997

TABLE OF CONTENTS

PART I. AUTHORIZATION TO CONVERT AND INJECT

Pursuant to the Underground Injection Control Regulations of the U. S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations, §§ 124, 144, 146, and 147,

Marathon Oil Company
1501 Stampede Avenue
Cody, WY 82414-4721

is hereby authorized to convert to a Class II enhanced recovery well the Shoshone 66 No. 66, SW SW (633' FSL & 840' FWL) Section 6, Township 6 North, Range 2 West, Fremont County, Wyoming. The well is within the exterior boundaries of the Wind River Indian Reservation. Injection shall be for the purpose of enhanced recovery of oil from the overthrust Phosphoria and Darwin Formations, Circle Ridge Field, in accordance with conditions set forth herein. <u>If the well is not converted within one (1) year from the effective date of this Permit, the well shall be plugged and abandoned according to Part II, Section A. 6.</u>

Injection activities shall not commence until the operator has fulfilled all applicable conditions of this Permit and has received written authorization from the Director. "Prior to Commencing Injection" requirements are set forth in Part II, Section C. 1. of this Permit.

All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations and are regulations that are in effect on the date that this Permit becomes effective.

This Permit consists of a total of forty-six (46) pages and includes all items listed in the Table of Contents. Further, it is based upon representations made by the permittee and on other information contained in the administrative record.

This Permit and the authorization to inject are issued for the life of the well, unless terminated (Part III, Section B). The Permit will be reviewed by EPA at least once every five (5) years to determine whether action under 40 CFR § 144.36 (a) is warranted. The Permit will expire upon delegation of primary enforcement responsibility for the UIC Program to the Wind River Tribes and/or the State of Wyoming, unless those Tribes or State have/has both adequate authority, and choose, to adopt and enforce this Permit as a Tribal or State Permit.

Issued: DEC 3 1997.

This Permit shall become effective: DEC 3 1997.

Kerrigan Clough

* Kerrigan G. Clough
Assistant Regional Administrator
Office of Pollution Prevention,
State and Tribal Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

A. WELL CONSTRUCTION REQUIREMENTS

1. Casing and Cementing. The construction details submitted with the application are hereby incorporated into this Permit as Appendix A, and shall be binding on the permittee.

2. Tubing and Packer Specifications. The permittee has the option to select that diameter tubing that will be most effective in the dual nature of the operation of this facility. Each packer will be set no more than 100 feet above the top Phosphoria and Darwin perforation. Injection between the outermost casing protecting underground sources of drinking water (USDW) and the wellbore is prohibited.

3. Monitoring Devices. The operator shall provide and maintain in good operating condition:

(a) a tap on each injection line for the purpose of obtaining representative samples of the injection fluids;

(b) three (3), one-half (1/2) inch Female Iron Pipe (FIP) fittings, isolated by plug or globe valves, and located: 1) at the wellhead on each tubing string; and 2) on the tubing/casing annulus, and positioned to allow attachment of 1/2 inch Male Iron Pipe (MIP) gauges;

(c) pressure gauges shall be attached to the FIP fittings of the: 1) tubings/casing annulus to allow for monitoring of the annulus fluid pressure; and 2) each tubing string to allow injection pressure monitoring. The gauges shall be designed to operate at a certified accuracy of at least ninety-five (95) percent, throughout the range of anticipated injection pressures; and

(d) flow meters with cumulative volume recorder that is certified for at least ninety-five (95) percent accuracy, throughout the range of injection rates allowed by the Permit.

4. Proposed Changes and Workovers. The permittee shall give advance notice to the Director, as soon as possible, of any planned physical alterations or additions to the permitted well. Major alterations or workovers of the permitted well shall meet all conditions as set forth in this Permit. A major

alteration/workover shall be considered any work performed, which affects casing, packer(s), or tubing.

Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of workovers/alterations and prior to resuming injection activities, in accordance with Permit Part II, Section C. 2.

The permittee shall provide all records of well workovers, logging, or other test data to EPA within sixty (60) days of completion of the activity. Permit Appendix B contains samples of the appropriate reporting forms.

5. Formation Testing. The permittee is required to determine the **injection zones fluid pore pressure** (static bottom-hole pressure).

The permittee will conduct a **step-rate injectivity test** of the Phosphoria and Darwin injection zones within six (6) months following commencement of injection.

Results of the two (2) above tests will be submitted to the EPA for review and approval.

6. Postponement of Conversion. If the well is not converted to injection status within one (1) year from the effective date of this permit, the well shall be plugged and abandoned according to Permit Appendix C, unless the permittee requests an extension. The request shall be made to the Director in writing, in lieu of the annual reporting requirements of Part II, Section D. 4., and shall state the reasons for the delay in conversion and confirm the protection of all USDWs. The extension under this section may not exceed one (1) year.

Financial responsibility shall be maintained during the period of inactivity in accordance with Part II, Section F. Once a Permit expires under this part, the full permitting process, including opportunity for public comment, must be repeated before authorization to inject will be reissued.

B. CORRECTIVE ACTION

The operator is not required to take any corrective action on the thirty-five (35) locations (identified on Page Two [2] of the Statement of Basis) within the one-quarter (1/4) mile area-of-review (AOR) before the effective date of this Permit.

Following commencement of injection into the Shoshone 66 No. 66 should upward fluid migration occur at the surface in any of the thirty-five (35) AOR wells, injection into the Shoshone 66 No. 66 will be immediately discontinued until the proper remedial work is performed, <u>and approved by letter from the EPA</u>. Any annular flowage within such well will be considered noncompliance with this Permit!

C. WELL OPERATION

1. <u>Prior to Commencing Injection</u>. Injection operations may not commence until the permittee has complied with (a) and (b), (c) and (d), as follows:

(a) Conversion is complete, and the permittee has submitted a Well Rework Record (Form 7520-12 in Appendix B); and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the permit; or

(ii) The permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within thirteen (13) days of the date the Director receives the Well Rework Record in paragraph (a) of this permit condition, in which case prior inspection or review is waived and the permittee may commence injection. However, in all circumstances, item (b), (c), and (d) below must be satisfied.

(b) The permittee determines the injection zone pore pressure (static fluid level).

(c) The permittee shows that the well has mechanical integrity in accordance with 40 CFR 146.8 and Part II, Section C. 2., below. The permittee shall notify EPA two (2) weeks prior to conducting this test so that a representative may be present to observe the test. Results of the test shall be submitted to the Director as soon as possible but no later than thirty (30) days after the demonstration.

(d) The permittee has received written notice from the Director that all demonstrations are satisfactory, and has been authorized to commence injection.

2. Mechanical Integrity.

(a) Method of Demonstrating Mechanical Integrity. A demonstration of the absence of significant leaks in the casing, tubing and/or packer must be made by performing a tubing/casing annulus pressure test. This test shall be for a minimum of forty-five (45) minutes at: (1) a pressure of 300 pounds per square inch gauge (psig) measured at the surface, if the well is shut-in; or (2) a pressure differential of 200 psig between the tubing and tubing/casing annulus, if injection activities are continued during the test. The tubing/casing annulus shall be filled with a non-corrosive fluid (either a non-toxic liquid or the injection liquid) at least twenty-four (24) hours in advance of the test. Pressure values shall be recorded at five (5) minute intervals. A well passes the mechanical integrity test if there is less than a ten (10) percent decrease or increase in pressure over the forty-five (45) minute period.

(b) Schedule for Demonstration of Mechanical Integrity. A demonstration of mechanical integrity shall be made at regular intervals, no less frequently than every five (5) years from the effective date of this Permit, in accordance with 40 CFR 146.8 and paragraph (a) above, unless otherwise modified. Initiation of mechanical integrity demonstrations will be according to the following provisions:

(i) It shall be the permittee's responsibility to arrange and conduct the routine five-year tubing/casing annulus pressure test demonstration. The permittee shall notify the Director of his intent to demonstrate mechanical integrity at least thirty (30) days prior to such demonstration. Results of the test shall be submitted to the Director as soon as possible but no later than sixty (60) days after a demonstration.

(ii) In addition to any demonstration made under paragraph (i) above, the Director may require a demonstration of mechanical integrity at any time during the permitted life of the well.

(c) Loss of Mechanical Integrity. If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity as defined by 40 CFR 146.8 becomes evident during operation, the permittee shall notify the Director in accordance with Part III, Section E. 10. of this Permit.

Furthermore, injection activities shall be terminated immediately; and operation shall not be resumed until the permittee has taken necessary actions to restore integrity to the well and EPA gives approval to recommence injection.

3. Injection Interval. Injection shall be limited to the overthrust Phosphoria-Tensleep-Amsden-Darwin Formations, between the gross depths of 462 feet to 1408 feet.

4. Injection Pressure Limitation.

(a) Injection pressure, measured at the surface, shall not exceed an amount that the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs.

(b) The exact pressure limit may be increased or decreased by the Director in order to ensure that the requirements in paragraph (a) are fulfilled. In order to determine an exact pressure limit, the permittee shall conduct a step rate injection test or other authorized well test(s) that will serve to determine the fracture pressure of the injection zone. Test procedures shall be pre-approved by the Director. The Director shall specify in writing, to the permittee, any increase or decrease to the injection pressure based on the test results and/or other parameters reflecting actual injection operations. Until such time that this demonstration is made, Phosphoria Formation injection pressure, measured at the surface, shall not exceed 244 psig, and the Darwin Formation injection pressure, measured at the surface, shall not exceed 910 psig.

5. Injection Volume Limitation. Injection volume will be limited to that which will not exceed the boundary of the defined exempted aquifer, i.e., the one-quarter (1/4) mile area-of-review (AOR) around the Shoshone 66 No. 66. It will be the responsibility of the operator to keep the injected fluids within the boundary of the exempted aquifer. Authorization to inject will terminate when the flood front reaches the boundary of the exempted portion of the reservoir.

6. Injection Fluid Limitation. Injection fluids are limited to those which are brought to the surface in connection with natural gas storage operations, or conventional oil and gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Fluids shall be further limited to those generated by sources owned or operated by the permittee. The permittee shall provide an annual listing of the sources of injected fluids and injected fluid analyses in accordance with the reporting requirements in Part II. Section D. 4. of this Permit.

7. Annular Fluid. The annulus between the tubing and the casing shall be filled with fresh water treated with a corrosion inhibitor, a scale inhibitor, and an oxygen scavenger; or other fluid as approved, in writing, by the Director.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program. Samples and measurements shall be representative of the monitored activity. The permittee shall utilize the applicable analytical methods described in Table 1 of 40 CFR § 136.3, or in Appendix III of 40 CFR Part 261, or in certain circumstances, by other methods that have been approved by the EPA Administrator. Monitoring shall consist of:

(a) Analysis of the injection fluid shall be performed at least once during the first year of operation for Total Dissolved Solids, pH, Specific Conductivity, and Specific Gravity.

(b) **40 CFR § 146.23 (b) (2) (ii):** Monthly observations of flow rates and cumulative volumes. At least one observation of each flow rate and each cumulative volume shall be recorded at regular intervals no greater than thirty (30) days.

(c) **40 CFR § 146.23 (b) (2) (ii):** Monthly observations of injection pressures and annulus pressure. Observations of injection pressures and annulus pressure shall be recorded monthly. Both operating parameters shall be measured at approximately the same time.

2. Monitoring Information. Records of any monitoring activity required under this Permit shall include:

(a) The date, exact place, the time of sampling or field measurements;

(b) The name of the individual(s) who performed the sampling or measurements;

(c) The exact sampling method(s) used to take samples;

(d) The date(s) laboratory analyses were performed;

(e) The name of the individual(s) who performed the analyses;

(f) The analytical techniques or methods used by laboratory personnel; and

(g) The results of such analyses.

3. Recordkeeping.

(a) The permittee shall retain records concerning:

(i) the nature and composition of all injected fluids until three (3) years after the completion of plugging and abandonment which has been carried out in accordance with the Plugging and Abandonment Plan shown in Appendix C, and is consistent with 40 CFR § 146.10.

(ii) all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation and copies of all reports required by this Permit for a period of at least five (5) years from the date of the sample, measurement or report throughout the operating life of the well.

(b) The permittee shall continue to retain such records after the retention period specified in paragraphs (a) (i) and (a) (ii) unless he delivers the records to the Director or obtains written approval from the Director to discard the records.

(c) The permittee shall maintain copies (or originals) of all pertinent monthly observation records [Part II., Section D.1.(b) and (c)] available for inspection at the office of Marathon Oil Company, Cody, Wyoming.

4. Reporting of Results. The permittee shall submit an Annual Report, whether injecting or not, to the Director summarizing the results of the monitoring required by Part II, Section D. 1. (a), (b) and (c) of this Permit. The permittee shall also include a listing of all sources of the fluids injected during the year identifying the source by either the well name(s), the field name(s), or the facility name(s).

The first Annual Report shall cover the period from the effective date of the Permit through December 31. Subsequent Annual Reports shall cover the period from January 1, through December 31. Annual Reports shall be submitted by February 15 of the year following data collection. Appendix B contains Form 7520-11 which may be copied and used to submit the Annual Report.

E. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment. The permittee shall notify the Director forty-five (45) days before conversion or abandonment of the well.

2. Plugging and Abandonment Plan. The permittee shall plug and abandon the well as provided in the Plugging and Abandonment Plan, Appendix C. EPA reserves the right to change the manner in which the well will be plugged if the well is modified during its permitted life or if the well is not made consistent with EPA requirements for construction and mechanical integrity. The Director may ask the permittee to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the well according to the plan.

3. <u>Cessation of Injection Activities</u>. After a cessation of operations of two (2) years, the permittee shall plug and abandon the well in accordance with the Plugging and Abandonment Plan, unless he:

(a) has provided notice to the Director; and

(b) has demonstrated that the well will be used in the future; and

(c) has described actions or procedures, satisfactory to the Director, that will be taken to ensure that the well will not endanger underground sources of drinking water during the period of temporary abandonment.

4. <u>Plugging and Abandonment Report</u>. Within sixty (60) days after plugging the well, the permittee shall submit a report on Form 7520-13 to the Director. The report shall be certified as accurate by the person who performed the plugging operation and the report shall consist of either: (1) a statement that the well was plugged in accordance with the plan; or (2) where actual plugging differed from the plan, a statement that specifies the different procedures followed.

F. FINANCIAL RESPONSIBILITY

1. <u>Demonstration of Financial Responsibility</u>. The permittee is required to maintain continuous financial responsibility and resources to close, plug and abandon the injection well as provided in the plugging and abandonment plan.

(a) The permittee shall submit financial statements and other information annually, or as required by EPA, in order to demonstrate that its financial position remains sound, and that it continues to have adequate financial resources, as determined by EPA, to close, plug, and abandon the injection well in accordance with the approved plugging and abandonment plan.

(b) If financial statements or other information indicate that the permittee no longer has financial resources, according to EPA criteria, to assure that the injection well will be properly plugged and abandoned, then the permittee must make an alternate showing of financial responsibility. The showing must be acceptable to the Director and must be submitted within sixty (60) days after having been notified by EPA of the necessity for making an alternate showing of financial responsibility.

(c) The permittee may upon his own initiative and upon written request to EPA, change the method of demonstrating financial responsibility from financial statement coverage to a financial instrument such as a bond, letter of credit, or trust fund. Any such change must be approved by the Director.

2. Insolvency of Financial Institution. In the event that an alternate demonstration of financial responsibility has been approved under (b) or (c), above, the permittee must submit an alternate demonstration of financial responsibility acceptable to the Director within sixty (60) days after either of the following events occur:

(a) The institution issuing the trust or financial instrument files for bankruptcy; or

(b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

3. Cancellation of Demonstration by Financial Institution. The permittee must submit an alternative demonstration of financial responsibility acceptable to the Director, within sixty (60) days after the institution issuing the trust or financial instrument serves 120-day notice to the EPA of their intent to cancel the trust or financial instrument.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The permittee, as authorized by this Permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR, Part 142 or otherwise adversely affect the health of persons. Any underground injection activity not authorized in this Permit or otherwise authorized by Permit or rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment for any imminent and substantial endangerment to human health, or the environment, nor does it serve as a shield to the permittee's independent obligation to comply with all UIC regulations.

B. PERMIT ACTIONS

1. Modification, Reissuance, or Termination. The Director may, for cause or upon a request from the permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR Sections 124.5, 144.12, 144.39, and 144.40. Also, the Permit is subject to minor modifications for cause as specified in 40 CFR Section 144.41. The filing of a request for a Permit modification, revocation and reissuance, or termination or the notification of planned changes or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any Permit condition.

2. Conversions. The Director may, for cause or upon a request from the permittee allow conversion of the well from a Class II injection well to a non-Class II well. Requests to convert the injection well from its Class II status to a non-Class II well, such as, a production well, must be made in writing to the Director. Conversion may not proceed until a Permit modification indicating the conditions of the proposed conversion is received by the permittee. Conditions of the

modification may include such items as, but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, and well specific monitoring and reporting following the conversion.

3. Transfers. This Permit is not transferrable to any person except after notice is provided to the Director and the requirements of 40 CFR 144.38 are complied with. The Director may require modification, or revocation and reissuance, of the Permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

4. Operator Change of Address. Upon the operator's change of address, notice must be given to the appropriate EPA office at least fifteen (15) days prior to the effective date.

C. SEVERABILITY

The provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, any information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the permittee; and
- Information which deals with the existence, absence or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply. The permittee shall comply with all conditions of this Permit, except to the extent and for the duration such noncompliance is authorized by an emergency Permit. Any Permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, Permit termination, revocation and reissuance, or modification. Such non-compliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions. Any person who violates a Permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to such actions pursuant to the RCRA. Any person who willfully violates Permit conditions may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity not a Defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Duty to Provide Information. The permittee shall furnish the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this Permit, or to determine compliance with the Permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit.

7. Inspection and Entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and

(d) Sample or monitor, at reasonable times, for the purpose of assuring Permit compliance or as otherwise authorized by the SDWA any substances or parameters at any location.

8. Records of Permit Application. The permittee shall maintain records of all data required to complete the Permit application and any supplemental information submitted for a period of five (5) years from the effective date of this Permit. This period may be extended by the Director at any time.

9. Signatory Requirements. All reports or other information requested by the Director shall be signed and certified according to 40 CFR 144.32.

10. Reporting of Noncompliance.

(a) Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements.

(b) Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than thirty (30) days following each scheduled date.

(c) Twenty-four Hour Reporting.

(i) The permittee shall report to the Director any noncompliance which may endanger health or the environment. Information shall be provided orally within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning EPA at (303) 312-6203 (during normal business hours) or at (303) 293-1788 (for reporting at all other times). The following information shall be included in the verbal report:

(A) Any monitoring or other information which indicates that any contaminant may cause endangerment to an underground source of drinking water.

(B) Any noncompliance with a Permit condition or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

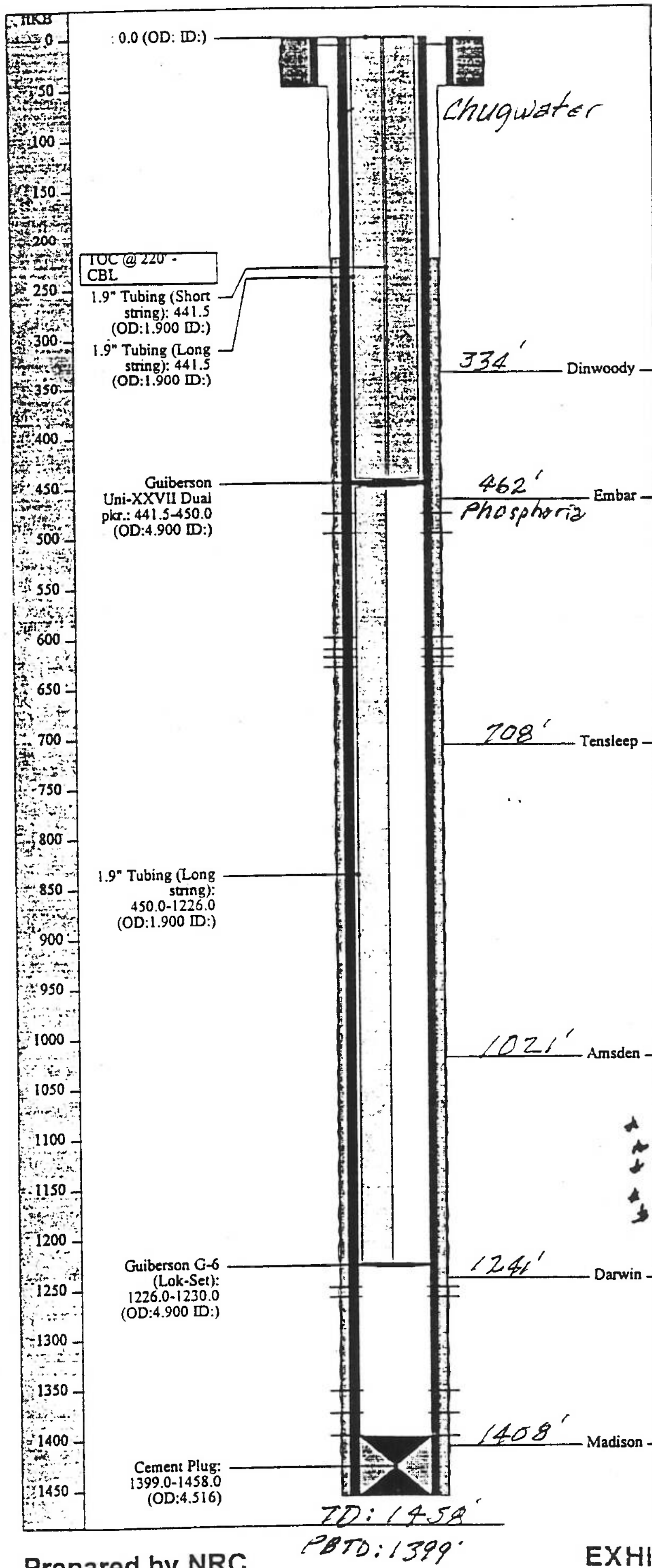
(d) Other Noncompliance. The permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part III, Section E. 10. (C) (ii) of this Permit.

(e) Other Information. Where the permittee becomes aware that any relevant facts were not submitted in the Permit application, or incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such correct facts or information within two (2) weeks of the time such information becomes known.

APPENDIX A (CONSTRUCTION DETAILS)

Shoshone 66 #66

Proposed



General Well Information

Lease Name - *Shoshone 66 #66*	
API Code - *49 013 20757*	
State - *Wyoming*	
County - *Fremont*	
District - *Rocky Mountain Region*	
Permit No. -	
TD Measured - *1458*	Permit -
Reservoir -	Spud - *Friday, January 20, 1978*
Field - *Circle Ridge*	Finish Drl - *Monday, January 30, 1978*
Field Code - *16296*	Completion - *Friday, February 10, 1978*
Basin -	Abandon -
Basin Code -	Not Used -

Well Location

Meridian -	
Twnship - *6N*	Not Used - *633' FSL, 840' FWL*
Range - *2W*	Not Used -
Section - *6*	Not Used -
Quarter - *SW SW*	Not Used -

Elevations (ft)

KB - *7068.0*	CF -
TH -	GRD - *7060.0*

Casing Equipment Report

Surface

Date Run	Date Pulled	Description	Top (ftKB)	Btm (ftKB)	Jnts	OD (in)	ID (in)	Wt (lbs/ft)	Grd	Thrd	Comments
1/22/78		Surface	0.0	48.0	1	8.625		24.00	K-55		

Production

Date Run	Date Pulled	Description	Top (ftKB)	Btm (ftKB)	Jnts	OD (in)	ID (in)	Wt (lbs/ft)	Grd	Thrd	Comments
1/31/78		Production	0.0	1458.0	34	5.500		15.50	K-55		

Casing Cement

String	Date	Top (ftKB)	Btm (ftKB)	Amnt (sx)	Comments
Surface	NA	0.0	48.0	50	
Production	NA	220.0	1458.0	300	CBL-TOC @ 220'

Formations / Horizons

Top (ftKB)	Btm (ftKB)	Not Used	Formation	Code	Not Used	Not Used	Comments
334.0	0.0	NA	Dinwoody				
462.0	0.0	NA	Embar				
708.0	0.0	NA	Tensleep				
1021.0	0.0	NA	Amsden				
1241.0	0.0	NA	Darwin				
1408.0	0.0	NA	Madison				

Perforations

Date	Top (ftKB)	Btm (ftKB)	Shots (/ft)	Type	Status	Comments
NA	476.0	496.0	3.0	Phosphoria		
NA	600.0	612.0	3.0	Phosphoria		
NA	620.0	630.0	3.0	Phosphoria		
2/2/78	1250.0	1260.0	2.0	Darwin		
2/2/78	1354.0	1398.0	2.0	Darwin		

Tubing Equipment Report

Long String

Date Run	Date Pulled	Description	Top (ftKB)	Btm (ftKB)	Jnts	OD (in)	ID (in)	Wt (lbs/ft)	Grd	Thrd	Comments
NA		1.9" Tubing (Long string)	450.0	1226.0	0	1.900				10 rd	
NA		Guiberson G-6 (Lok-Set)	1226.0	1230.0	0	4.900					
NA		1.9" Tubing (Long string)	0.0	441.5	0	1.900				10 rd	
NA			0.0	0.0	0						
NA		Guiberson Uni-XXVII Dual pkr.	441.5	450.0	0	4.900					

Short String

Date Run	Date Pulled	Description	Top (ftKB)	Btm (ftKB)	Jnts	OD (in)	ID (in)	Wt (lbs/ft)	Grd	Thrd	Comments
NA		1.9" Tubing (Short string)	0.0	441.5	0	1.900				10 rd	

Prepared by NRC

EXHIBIT #6

3/27/97

APPENDIX B (REPORTING FORMS)

1. EPA Form 7520- 7: APPLICATION TO TRANSFER PERMIT
2. EPA Form 7520-10: COMPLETION REPORT FOR BRINE DISPOSAL WELL
3. EPA Form 7520-11: ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT
4. EPA Form 7520-12: WELL REWORK RECORD
5. EPA Form 7520-13: PLUGGING RECORD
6. GUIDANCE FOR MECHANICAL INTEGRITY TEST

Ref: 8WM-DW

MEMORANDUM

SUBJECT: **Final Guidance for Conducting a Pressure Test to Determine if a Well Has Leaks in the Tubing, Casing or Packer**

FROM: Tom Pike, Chief UIC Direct Implementation

TO: UIC Direct Implementation Permit Writers

Introduction

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

(1) There is no significant leak in the tubing, casing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore.

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the downhole components of an injection well, usually tubing, casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. **If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equivalent form containing the necessary information. A pressure recording chart documenting the actual annulus test pressures must be attached to the form.**

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all class I and II wells. Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

Pressure Test Description

Test Frequency

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required at least every five (5) years. **If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. The Regional UIC program must be notified of the workover and the proposed date of the pressure test. The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate.** Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

1. Class I hazardous waste injection wells; initially [40 CFR 146.68(d)(1)] and annually thereafter;

2. Class I non-hazardous waste injection wells; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);

3. Class II wells with tubing, casing and packer; initially and at least every five (5) years thereafter;

4. Class II wells with tubing cemented in the hole; initially and every one (1) or two (2) years thereafter depending on well specific conditions (See Region VIII UIC Section Guidance #36);

5. Class II wells which have been temporarily abandoned (TAd) must be pressure tested after being shut-in for two years; and

6. Class III uranium extraction wells; initially.

Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.

Test Criteria

1. The duration of the pressure test is 30 minutes.

2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.

3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.

4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. **Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equivalent form . A pressure recording chart documenting the actual annulus test pressures must be attached to the submittal.** The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.

2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.

3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.

4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.

5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to

the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:

6. Read tubing pressure and record on the form. If the well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.

7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.

8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.

9. Hook-up well to pressure source and apply pressure until test value is reached.

10. Immediately disconnect pressure source and start test time. (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted.) The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.

11. Record tubing and annulus pressure values every five (5) minutes.

12. At the end of the test, record the final tubing pressure.

13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.

14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up

letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.

15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.

16. Return to office and prepare follow-up.

Alternative Test Option

While it is expected that the test procedure outlined above will be applicable to most wells, the potential does exist that unique circumstances may exist for a given well that precludes or makes unsafe the application of this test procedure. In the event that these exceptional or extraordinary conditions are encountered, the operator has the option to propose an alternative test or monitoring procedures. The request must be submitted by the operator in writing and must be approved in writing by the UIC-Implementation Section Chief or equivalent level of management.

Attachment

APPENDIX C (PLUGGING & ABANDONMENT PLAN)

<u>Plugging and Abandonment Plan</u>

Plug #1 - Fill 5-1/2 inch casing with cement from surface to total depth.

Plug #2 - Within the annulus between the 5-1/2 inch casing and 8-5/8 inch casing, set a cement plug from the surface to 98 feet.

APPENDIX D

GUIDELINES: STEP-RATE INJECTIVITY TEST

SUGGESTED STEP-RATE INJECTIVITY TEST PROCEDURES

The Step-Rate Test (SRT) results will be documented with service company or other appropriate (acceptable) records and/or charts and should be witnessed by an EPA inspector.

The Step-Rate Test Procedure is as follows:

1) The well should be shut in long enough prior to testing that the bottom hole pressures approximate shut-in formation pressures. If the shut-in well flows to the surface, the wellhead injection string will be equipped with a gauge and the static surface pressure will be read and recorded.

2) A series of successively higher injection rates will be established as suggested below, with the elapsed time and pressure values read and recorded for each rate. Each step should last <u>exactly</u> as long as the preceding rate. If stabilized pressure values are not obtained within the times suggested below, the test will result in inconclusive results due to a high permeability and/or underpressured injection zone.

Formation Perm (md)	Time per step-rate (min)
≤ -5 md	60 min
≥ 10 md	30 min

3) Suggested injection rates:

5%	Of Maximum Anticipated Injection Rate
10%	
20%	
40%	
60%	
80%	
100%	

4) Injection rates should be controlled with a constant flow regulator that has been tested prior to use. A throttling device is not sufficient.

5) Flow rates should be measured with a calibrated turbine flowmeter.

6) Record injection rates with a chart recorder or a strip chart.

7) Measure pressures with a down hole pressure bomb.

8) Measure and record injection pressures with a gauge or recorder (for immediate test results).

9) A plot of injection rates and the corresponding stabilized pressure values should be graphically represented as a constant slope straight line to a point at which the formation "breakdown" pressure is exceeded. The slope of the subsequent straight line should be less than that of the before-fracture straight line.

10) If the fracture pressure has definitely been exceeded with at least two injection rate-pressure combinations greater than the "breakdown" pressure, the injection pump should be stopped and the line valve closed so that the pressure is allowed to bleed-off into the injection formation. There will be an immediate pressure fall-off (Instantaneous Shut-in Pressure or ISIP), after which the pressure values begin to level out. The ISIP will be read and recorded.

11) Once the ISIP is obtained, the SRT is concluded. The ISIP obtained in this manner may be considered the minimum pressure required to hold the fracture open.

12) In the event that formation "breakdown" was not obtained at the maximum test injection pressure utilized, the test results may indicate that the formation is accepting fluids without fracturing.

This SRT outline is consistent with acceptable oilfield practices. It should identify an allowable injection pressure which will provide adequate protection of the underground sources of drinking water at an injection well having demonstrated mechanical integrity. The allowable injection pressure will be determined after an EPA review of the SRT results. Enclosed is a form which you may copy and use to record test data.

STEP-RATE TEST DATA

STEP #1 Test Rate (5% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #2 Test Rate (10% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #3 Test Rate (20% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #4 Test Rate (40% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #5 Test Rate (60% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #6 Test Rate (80% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

STEP #7 Test Rate (100% max rate) ________ (bbl/min)

Time (min) :	____	____	____	____	____	____	____
Pressure (psi):	____	____	____	____	____	____	____

ISIP : __________ (psi)

SRT EXAMPLE

The following is an example of a Step-Rate Test with tabular and graphic results. The operator of Anywell #1 set up a SRT for the following conditions:

A) Maximum anticipated injection rate was 4 bbl/min.

B) Following the recommended test procedures, the operator planned on using these rates for the test:

1) 5% of 4 bbl/min = 0.2 bbl/min
2) 10% of 4 bbl/min = 0.4 bbl/min
3) 20% of 4 bbl/min = 0.8 bbl/min
4) 40% of 4 bbl/min = 1.6 bbl/min
5) 60% of 4 bbl/min = 2.4 bbl.min
6) 80% of 4 bbl/min = 3.2 bbl/min
7) 100% of 4 bbl/min = 4.0 bbl/min

C) The formation permeability is estimated as 100 md, therefore each step will last for 30 minutes.

The step-rate test data and graphic results of the test are on the following pages. For this test, the injection formation broke down at approximately 1200 psi, and the ISIP was listed as 1000 psi. Since the injection formation will part at 1000 psi, the maximum injection pressure will be held to the ISIP.

If the formation had not broken down at 1200 psi, the maximum allowable injection pressure would be the maximum pressure obtained during the test.

STEP-RATE TEST ANYWELL #1

STEP #1 Test Rate (5% max rate) 0.2 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	0	90	95	98	99	100	100

STEP #2 Test Rate (10% max rate) 0.4 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	80	170	185	195	199	200	200

STEP #3 Test Rate (20% max rate) 0.8 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	190	325	385	392	398	399	400

STEP #4 Test Rate (40% max rate) 1.6 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	380	700	790	792	795	798	800

STEP #5 Test Rate (60% max rate) 2.4 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	750	990	1030	1090	1150	1180	1200

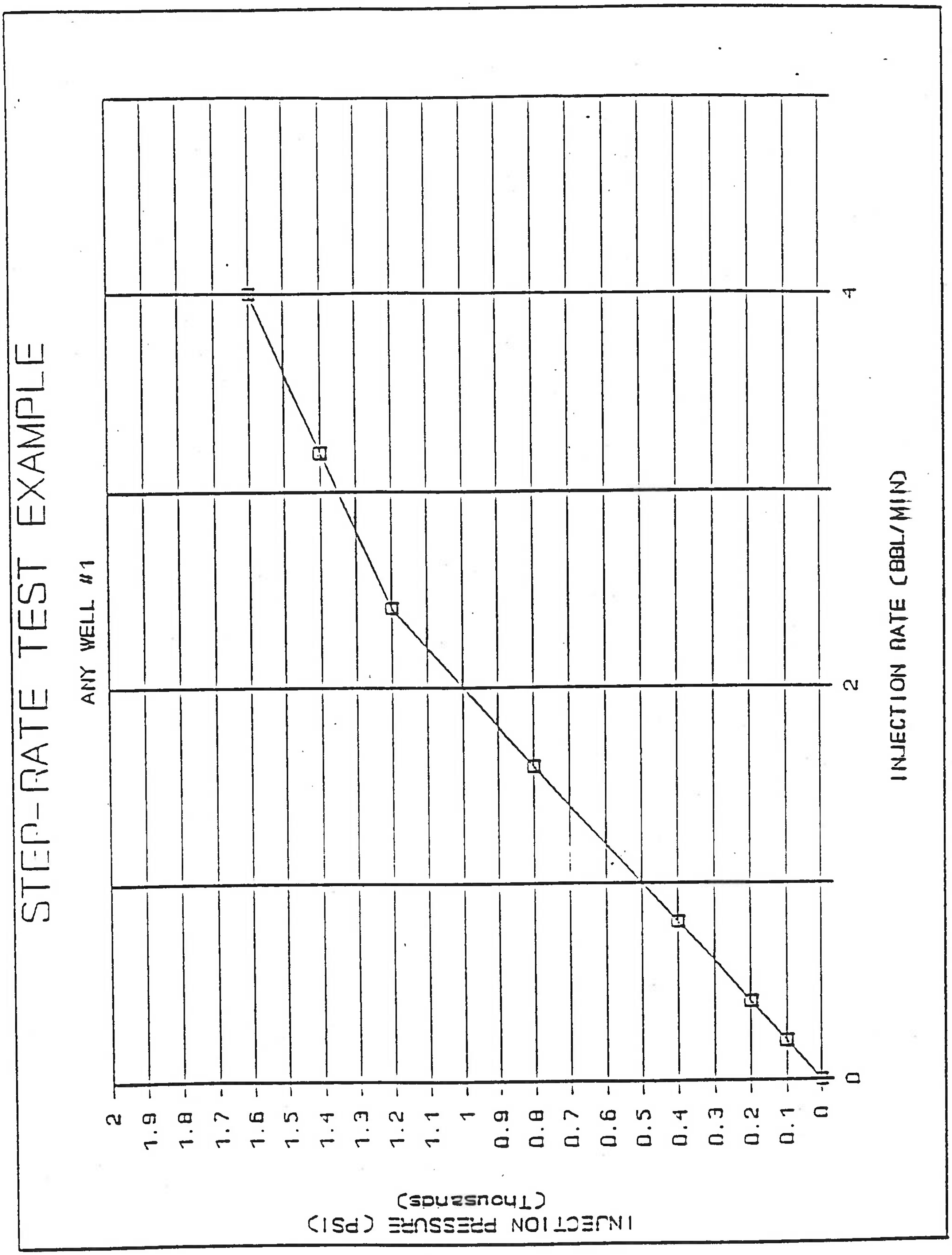
STEP #6 Test Rate (80% max rate) 3.2 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	1100	1250	1325	1370	1390	1395	1400

STEP #7 Test Rate (100% max rate) 4.0 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	1350	1450	1500	1530	1570	1590	1600

ISIP : 1000 (psi)


STEP-RATE TEST EXAMPLE
ANY WELL #1
INJECTION PRESSURE (PSI)
(Thousands)
INJECTION RATE (BBL/MIN)
0
2
4
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2

STATEMENT OF BASIS

MARATHON OIL COMPANY
SHOSHONE 66 NO. 66
SW SW (633' FSL & 840' FWL) SEC. 6 - T6N - R2W
CIRCLE RIDGE OIL FIELD
FREMONT COUNTY, WYOMING
EPA PERMIT NUMBER: WY2819-04366

CONTACT: Emmett R. Schmitz
U. S. Environmental Protection Agency
UIC Implementation Section, 8P2-W-GW
999 18th Street, Suite 500
Denver, Colorado 80202-2466
Telephone: (303) 312-6174

DESCRIPTION OF FACILITY AND BACKGROUND INFORMATION:

On April 4, 1997, Marathon Oil Company (Marathon), Cody, Wyoming, made application for an Underground Injection Control Permit for the injection of produced water from several formations in the Circle Ridge Field, into the overthrust Phosphoria and Darwin Formations. The proposed dual injection enhanced recovery well is the Circle Ridge Shoshone 66 No. 66, currently a shut-in Darwin oil well. **In consideration that Marathon Oil Company could consider enhanced recovery of the Tensleep and Amsden Formations (both productive of oil in the one-quarter [1/4] mile are of review), the Environmental Protection Agency (EPA) has delineated the gross interval Phosphoria-Tensleep-Amsden-Darwin as the permitted injection interval in the Shoshone 66 No. 66. When Marathon Oil Company elects to inject into the Tensleep and/or Amsden, EPA approval will be accorded via a Minor Permit Modifcation (40 CFR § 144.40 (f).**

Circle Ridge Field is within the exterior boundary of the Wind River Indian Reservation.

The total dissolved solids (TDS) content of the Darwin Formation water, by submitted water analysis, is 911 mg/l. The TDS of the Phosphoria is analyzed at 2710 mg/l. Marathon also submitted a third water analysis of combined "tank" water from the Phosphoria, Tensleep, Madison, Amsden and Darwin Formations. This "tank" sample analysis shows a TDS of 971 mg/l. Specific gravity (SG) of the injected water is assumed to be 1.01.

Based on the analysis of produced Phosphoria water (2710 mg/l TDS), Tensleep water (1875 mg/l, Amsden (less than 10,000 mg/l) and produced Darwin water (911 mg/l TDS), an Aquifers Exemption (AE) will be issued for all the afore-mentioned formations within the one-quarter (1/4) mile area-of-review (AOR) around the Shoshone 66 No. 66. The Exemption will be granted because:

Marathon has submitted all required information and data necessary for Permit issuance in accordance with 40 CFR Parts 144, 146 and 147, and a Final Permit has been prepared. The Permit will be issued for the operating life of the well, unless terminated for reasonable cause (40 CFR 144.39, 144.40 and 144.41). However, the Permit will be reviewed every five years.

This Statement of Basis gives the derivation of the site-specific Permit conditions and reasons for them. The referenced sections and conditions correspond to the sections and conditions in Permit WY2819-04366. The general Permit conditions, for which the content is mandatory and not subject to site-specific differences (based on 40 CFR Parts 144, 146 and 147), are not included in the discussion.

PART II, Section A WELL CONSTRUCTION REQUIREMENTS

Casing and Cementing (Condition 1)

The following casing and cementing details were submitted with the Permit application:

(1) Surface casing (8-5/8 inch) is set in a 12-1/4 inch diameter hole to a depth of 48 feet Kelly Bushing (KB). Fifty (50) sacks of Class "G" cement, used to secure the casing, was circulated to the surface isolating the casing from the wellbore.

(2) The well was drilled to total depth (TD) of 1458 feet with a 7-7/8 inch bit. 5-1/2 inch casing was set at a depth of 1458 feet KB. The casing was secured with 100 sacks of 50/50 Pozmix and 200 sacks of Class "G" cement. Top of cement by cement bond log (CBL) is 225 feet, or 251 feet above the proposed Phosphoria injection zone. Between CBL log depths of 1393 feet and 225 feet annulus cement meets EPA requirements.

(3) The well was originally completed for oil production in Darwin perforations: 1250 feet - 1260 feet, and 1354 feet - 1398 feet. These perforations will also be used for enhanced recovery.

The permittee anticipates perforating the Phosphoria Formation 476 feet to 496 feet, 600 feet to 612 feet, and 620 feet to 630 feet for enhanced recovery..

A 128-foot Dinwoody Formation confining zone (334 feet to 462 feet) above the Phosphoria injection interval (476 feet to 630 feet), contains impervious shale, anhydrite, anhydritic limestone and siltstone. The confining zone has adequate cement.

The EPA has analyzed the CBL for protection of USDWs, and it is the conclusion of the EPA that all USDWs are protected from annulus communication. Intervals of annulus cement with 80% effectiveness, or greater, are cited below.

USDWs in this area are:

Formation	Depth	Water Quality (mg/l TDS)
Chugwater	Surface - 334'	Possible but Unknown
Dinwoody	334' - 462'	2000
Phosphoria	* 462' - 708'	1118 - 2710
Tensleep	* 708' - 1021'	1875
Amsden	1021' - 1241'	Unknown
Darwin	* 1241' - 1408'	911

(*) Formations under waterflood in Circle Ridge Field.

Tubing and Packer Specifications (Condition 2)

The applicant has the option to select the tubing size most convenient for facility operation. The Shoshone 66 No. 66 will be a dual enhanced recovery well, with perforations open in both the Phosphoria and Darwin Formations.

Two strings of tubing will be run inside of the 5-1/2 inch casing. Neither packer, i.e., for the Phosphoria tubing and the Darwin tubing, will be set more than 100 feet above each injection zone.

Monitoring Devices (Condition 3)

The permittee shall install: A one-half (1/2) inch fitting with a cut-off valve at the wellhead on each tubing string; similar fitting and cut-off valve for the casing/tubing annulus; flow meters that will be used to measure cumulative volumes of injected fluid into each tubing string; and pressure gauges attached to each tubing string and tubing/casing annulus to allow for monitoring of the injection and annulus fluid pressures. The permittee shall also install a sampling tap on each line to the injection well.

Injection into the Shoshone 66 No. 66 will be accomplished by means of a vertical centrifugal pump located at the Circle Ridge waterflood plant. Water from the treating facility will enter a surge tank, from which it will be delivered to the well by the centrifugal pump. Two (2) inch flow lines will be installed to transfer the water from the supply line to the well.

Formation Testing (Condition 5)

The permittee will determine the injection zones fluid pore pressure (static bottom-hole pressure), and perform a step-rate injectivity test of each injection interval, within six (6) months following the Director's letter authorizing Marathon Oil Company to commence injection.

PART II, Section B CORRECTIVE ACTION

Within a one-quarter (1/4) mile AOR surrounding the Shoshone 66 No. 66 there are thirty-five (35)locations. All thirty-five (35) wells are identified on page two (2) of this Statement of Basis as to their current status. Schematic diagrams have been submitted with the application, which diagrams also contain detailed construction data. The permittee is not required to perform any corrective action prior to the issuance of this Permit. **IF AS A RESULT OF INJECTION INTO THE SHOSHONE 66 NO. 66, UPWARD FLUID MIGRATION OCCURS BEHIND CASING IN ANY OF THE THIRTY-FIVE (35) AOR WELLS, INJECTION INTO THE SHOSHONE 66 NO. 66 WILL BE IMMEDIATELY DISCONTINUED UNTIL THE PROPER REMEDIAL WORK IS PERFORMED, AND APPROVED BY THE EPA. ANY FLOWAGE WITHIN SUCH WELL WILL BE CONSIDERED NONCOMPLIANCE WITH THIS PERMIT!**

PART II, Section C WELL OPERATION

Prior to Commencing Injection (Condition 1)

Injection will not be allowed to commence until the permittee has determined the injection zone pore pressure, submitted a Well Rework Record (EPA Form 7250-12), and a mechanical integrity pressure test has been performed, witnessed and approved according to the guidelines discussed in an Appendix to the Permit. Further, the applicant must receive a letter from the Director authorizing Marathon to commence injection.

Mechanical Integrity (Condition 2)

Tubings/casing annulus pressure tests must be repeated at least every five (5) years to demonstrate continued tubing, packer, and casing integrity.

Injection Interval (Condition 3)

Injection will be limited to the gross overthrust Phosphoria - Tensleep - Amsden - Darwin Formations, 462 feet - 1408 feet.

Injection Pressure Limitation (Condition 4)

The permittee submitted a formation-face fracture gradient of 0.995 psig/ft for the overthrust Phosphoria, based on the results of a Tensleep fracture stimulation treatment (ISIP: 795 psig) in the Shoshone No. 65-64. The EPA does not consider a Tensleep ISIP as valid for the Phosphoria. The EPA will temporarily allow a maximum surface injection pressure based upon a Marathon calculated Phosphoria fracture gradient of 0.949 psi/ft (After a Phosphoria nitrogen surge treatment yielding an ISIP of 729 psi/ft in the Circle Ridge 66 No. 56 [SW SW SE Sec. 6 - T6N - R2W, or 1/4-mile southeast of the referenced application]).

Frac Stimulation 66-64 1,165 psi

TO CALCULATE MAXIMUM SURFACE INJECTION PRESSURE

$$MIP = (FG) - [(S_g)(0.433)]\ (d)$$

MIP = Maximum surface injection pressure
FG = Formation-face fracture gradient: 0.949 psi/ft
h = depth to top perforation : 476 feet
S_g = specific gravity of fluid: 1.01

$$MIP = (0.949) - [(1.01)(0.433)]\ 476$$

MIP = 244 psig - PP

The surface injection pressure of 244 psig is temporarily approved for this well. Actual maximum injection pressures will be determined on the basis of a step-rate injectivity tests of the separate injection zones. Permit provisions have been made that allow the Director to increase or decrease the injection pressures based on the results of the tests. The tests are to be conducted within six (6) months following injection operation.

Injection Volume Limitation (Condition 5)

Injection volume will be limited to that which will not exceed the boundary of the defined exempted aquifer, i.e., the one-quarter (1/4) mile AOR around the Shoshone 66 No. ~~30~~ 66. It will be the responsibility of the operator to keep the injected fluids within the boundary of the exempted aquifer. Authorization to inject will terminate when the flood front reaches the last of the producing Phosphoria-Darwin oil wells.

Injection fluids are limited to those which are brought to the surface in connection with natural gas storage operations, or conventional oil and gas production and may be commingled with waste water from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Fluids shall be further limited to those generated by sources owned or operated by the permittee.

Annular Fluid (Condition 7)

The annulus between the tubing and the casing shall be filled with fresh water treated with a corrosion inhibitor, and a diesel freeze blanket may be circulated from surface to below frost level at completion to prevent freezing and possible equipment failure during winter months, or other fluid as approved in writing by the Director.

PART II, Section D MONITORING, RECORDKEEPING AND REPORTING OF RESULTS

Injection Well Monitoring Program (Condition 1)

Injection fluids are limited to those identified in 40 CFR § 144.6(b)(2) as fluids used for enhanced recovery of oil or natural gas. The permittee shall provide a listing of the sources of injected fluids on an annual basis as required by the permit. The permittee is required to submit a water analysis report of the injection fluid at least once during the first year of authorization. A water sample of injected fluids shall be analyzed for total dissolved solids, pH, specific conductivity, and specific gravity.

In addition, monthly observations of flow rate and cumulative volume will be made. At least one observation each for flow rate and cumulative volume will be recorded on a monthly basis. This record is required to be reported to EPA annually.

Injection pressure and annulus pressure will be observed on a monthly basis, and recorded on a monthly basis. This record is required to be reported to EPA annually.

PART II, Section E PLUGGING AND ABANDONMENT

Plugging and Abandonment Plan (Condition 2)

The following plugging and abandonment plan, submitted by the applicant, has been modified. The applicant's Plugs No. 1 and No. 2 have been combined into EPA Plug No. 1, below. The EPA has added Plug No. 2, below.

Plug No. 1: Fill the 5-1/2 inch casing with cement from surface to total depth.

Plug No. 2: Fill the annulus between the 5-1/2 inch casing and the 8-5/8 inch casing with cement from surface to 98 feet.

Part II, Section F FINANCIAL RESPONSIBILITY

Demonstration of Financial Responsibility (Condition 1)

The permittee has chosen to demonstrate financial responsibility through a 1996 Financial Statement which has been evaluated and approved.

UNITED ST ES ENVIRONMENTAL PROTECT N AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

FINAL
UNDERGROUND INJECTION CONTROL
AQUIFERS EXEMPTION
for
Marathon Oil Company
Shoshone 66 No. 66
EPA Permit WY2819-04366
Circle Ridge Oil Field
Wind River Indian Reservation

In compliance with provisions of the Safe Drinking Water Act, as amended, (42 USC 300f-300j-11, commonly known as the SDWA) and attendant regulations incorporated by the U.S. Environmental Protection Agency under Title 40 of the Code of Federal Regulations (CFR), the Phosphoria-Tensleep-Amsden-Darwin Formations located:

(1) in the subsurface interval approximately 462 feet to 1408 feet; and

(2) laterally within a one-quarter (1/4) mile radius of the Shoshone 66 No. 66, which is located 633 feet from the south line and 840 feet from the west line, Section 6, Township 6 North, Range 2 West in Fremont County, Wyoming,

are exempted as underground sources of drinking water (USDW).

This Aquifers Exemption is granted in conjunction with the Underground Injection Control Permit WY2819-04366 issued to Marathon Oil Company for the enhanced recovery of oil.

Date: NOV - 3 1997

Kerrigan Clough

Kerrigan G. Clough
Assistant Regional Administrator
Office of Pollution Prevention,
State and Tribal Assistance